Stranded Gas Hearings

(0406171000 Minutes)

Costs and Tariffs from Alberta to Lower 48: New Pipeline vs. Use of Existing Pipelines

John Carruthers, Vice President, Northern Development, Enbridge
Jack Crawford, Executive Vice President and Chief Operating Officer, Alliance Pipeline
Tony Palmer, Vice President, Alaska Business Development, TransCanada

MR. JOHN CARRUTHERS, Vice President of Northern Development at Enbridge, informed members that Enbridge has submitted an application that was approved under Alaska's Stranded Gas Development Act. He said the goal of his presentation is to provide context to some of the questions members have regarding what must happen to the gas once it reaches Alberta. He noted that recently, the Canadian producers could not ship stranded gas out of Alberta due to pipeline constraints. They found the most economical way to move the gas was through Alliance, a new high-pressure liquid-rich system that is consistent with Alaska's needs. Alliance began service in 2001 and was considered to be very successful by the industry. Enbridge worked with producers throughout the process and now owns 50 percent of Alliance. He introduced Jack Crawford, the Chief Operating Officer of Alliance Pipeline and noted that Mr. Crawford has been with Alliance throughout conception, construction, and operation.

MR. CARRUTHERS began by explaining that Enbridge has 50 years of experience in pipeline transmission. It owns and operates the world's largest crude oil pipeline system, which moves crude oil from the Western Canadian sedimentary basin through the Midwest. Enbridge also owns the Norman Wells pipeline; therefore Enbridge is the only pipeline company with extensive experience in the construction and operation of pipelines in continuous and discontinuous permafrost. He continued:

> We also bring a market perspective as the largest gas distribution company in Canada, shown in yellow, but today we want to focus on our experience in completing the Alliance pipeline. Again, it was a response to a consistent situation – pipeline-constrained gas, in this case in Alberta. It's a high-pressure liquid-rich line that transverses both the U.S. and Canada and was permitted efficiently in both Canada and the U.S. That line is shown in red on the map that you have.
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> I think we can skip forward a bit. I've given some of this information to some of you previously and some of it was discussed earlier. I really want to go to the forecast of Canadian supply. It's going to be very key and this forecast is back a few pages in your presentation. It's consistent with many and shows continuing growing production out of the Western Canadian sedimentary basin although a key consideration is much of this portion of growth is from natural gas from goal. So we do have a huge asset in Canada that parallels that of the United States in terms of size but certainly we haven't developed it nearly as much as the U.S. has. Less that 1 percent of our total production is from gas from coal, in comparison to over 10 percent in the United States, although we have a similar resource. It will require significant capital going forward and, given the decline of traditional reserves, our expectation is that capital will come but it's very important to continue to watch that. Clearly, the key for that in Canada is the use of water, something that has some opposition to the development of coal bed methane but we think there's a significant resource that can be developed.
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> This graph is very relevant. You'll see a significant decline in the lower portion, which is Alberta conventional. Again, we would see coal bed methane being able to make up a significant portion of that decline. But I think what's more important, this graph is relevant, it's about the time that Alaska gas will come on in 2012, 2015 period, so it's quite relevant. Really what's important is what will the picture look like going forward from 2015 because we'll have investment in a 30-year asset and we'd like to have consideration.
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> I think what we're trying to show here is that although we can have forecasts and they're well thought through, there's considerable uncertainty with what actually [it] will look like – what production will look like out of the Western Canadian basin. So it's something that we'll have to have a number of alternatives that we need to consider.

So let's start with where the gas goes today with the capacity of the pipelines. The good news is that there is well-developed infrastructure out of Alberta and there will be competitive options for Alaska gas. There is the potential to fill underutilized capacity. I think Tony will talk to you a little bit about that today. In the red - and these graphs as I mentioned, are relative, TransCanada is the largest – moves much of the gas out of the system. Eastern Gas, as you can see on the graph, handles 7 bcf per day and today you'll see something in the order of 2 bcf per day of spare capacity. As you look at the other pipeline systems, Alliance, Northern Border, Duke are all near capacity and they would have existing shippers with contractual rights.

When you look at the capacities from a producer perspective, which includes royalty owners like Alaska and Alberta governments, you want the pipeline systems to remain below full capacity to avoid bottlenecks and reduce prices. We went through that situation prior to the construction of Alliance and as a producer they saw significantly reduced prices, so you always want to have some extra capacity in your system. You don't want significant underutilized assets, as those have associated costs.

So it does provide good context to understand these systems today but again, you'll have to take that previous forecast and overlay it on these systems to see what they look like going forward. I think you'd also have to be cognizant of what capacity remains going forward. It is possible that certain capacity would be taken out of the system if it's not being utilized so it could be retired so some of the capacity lines could change as well. So it's very important to understand the systems and the capacity of those. It's also important to understand what the contractual commitments are with each of those. As we heard yesterday, there's a number of – the existing shippers will have rights to certain capacity. So again, it would be important to look at the contract [expirations] over the course of development of Alaska gas. As you can see from this graph, many of the contracts expire. Typically they can be renewed on one-year extensions with six months notice. So again, just in terms of consideration of the project and downstream opportunities, people have to be cognizant of what shippers are on what systems and what rights they have. Alliance itself has signed 15-year shipper pay agreements that could expire in 2015.

Again, I think this slide is included just to show that once you reach the Western Canadian sedimentary basin, there is significant optionality out of there to markets across North America and what we wanted to look at was the capacity outlook going forward. I think it's good context to understand what's happening today, what might happen when MacKenzie gas comes on-stream and then look at what might happen once Alaska's gas arrives.

So if you look at the top right hand corner, which summarizes it, I won't go through this entire slide but I think it does provide good context for people to work through. Today the Western Canadian sedimentary basin produces about 17 bcf per day and we export 12. Supply is expected to increase with MacKenzie by 2010 and Alaska gas certainly by 2015. At the same time, Alberta demand will increase largely in response to the oil sands development. So you have to look at the Western Canadian sedimentary basin production, what's coming in from MacKenzie and Alaska, and then what is the internal market within Alberta. So the box immediately below the one in the top right hand corner, we are looking at the pipeline capacity based on the earlier throughput. And today, you'd look at it and say we have something in the order of 3.3 bcf per day of spare capacity, but again, I'd caution you as a royalty owner, you do want some spare capacity. On a practical basis, we think there's more like 1.5 to 2 bcf per day of practical underutilization.

If you work down that line based on the previous forecast, it shows that we need 2.1 bcf per day of new pipeline capacity. Again there are a lot of factors that go into that forecast. It's consistent with most around but you would want something like a 90 percent load factor in order to manage your load. You don't want to be full up against the pipeline utilization. If you take that into account, you need something in the order of new pipeline capacity at 4 bcf per day if you assume Alaska gas is in the order of 5 bcf per day at that time. It could be a situation where you do need a full 4 bcf per day pipeline.

At that amount, Alliance would have the lowest cost option - would be to loop Alliance and would be the most attractive option. But again, that's not the only [indisc.]. You'd still have to look forward past 2015 to what the Canadian sedimentary basin is doing, what's spare capacity. You could have a situation where the more measured approach that Enbridge had proposed might fit better where you have some underutilization of capacity and you build a pipeline that could handle more like 2.5 bcf per day out of Alaska initially with expansion to 5 going forward. Again, there are some scenarios. You'd want to keep your optionality open as developments occur as we get better insight as to whether there is coal bed methane development in Alberta, how the existing basin is progressing, and the timing of Alaska gas. The bottom line is you'd want to maintain optionality.

Clearly, of course, the advantage to not having to build the pipeline out of Alberta is its cost is estimated to be close to $5 billion, so if you can utilize existing capacity, there could be significant advantage.

Some of the key points I think we should be cognizant of that – I mean Alberta should have significant capacity to handle Alaska gas by a phased approach. If you expect 2.5 bcf of spare capacity, if you need a full 4, Alliance would be your most economic option at this point. And then there's ways too, if you don't need it all, you'll see a number of the pipelines that could have a spare capacity and you see a more – potentially PG&E has some spare capacity, Duke has about 200 million, Alliance has 500 million, so you could have a way to make up the needed volumes with a variety of pipes, TransCanada, Alliance, et al.

I think again on this slide – again, I'm not wanting to necessarily go through all of the numbers. Really to take away I think you'll want to recognize in terms of tolls, tariffs – tolls are important but also, of course, the fuel is important, particularly at the high gas prices – from Alaska gas development, high gas prices are positive, in terms of the fuel cost they are not. So you certainly, you know, alternatives downstream you need to look at tolls plus fuel and the other thing that's most important...[end of tape]

MR. CARRUTHERS continued:

[new tape begins]...additional volumes - what the expectation is and what those volumes would be, and what those tolls would be with new expanded volumes, both from a toll and fuel perspective.

So tolls are clearly important but you have to also understand which market you're going to. Again, some historical reference as to what the spreads have been between Alberta and current markets in the United States. [Indisc.] toll the pipeline and the advantage of going there is an important consideration. You'd need to look at – always in pipeline development you need to look at what happens if you do build a pipeline and what happens if you don't build a pipeline in all scenarios and I think that will dictate where much of this gas will ultimately go. And really, what you'd really want to have, from a resource ownership perspective, is a competitive alternative out of Alberta when it comes and probably, as you heard yesterday, the best way is to have an open season where there are proposals from different proponents and then the market, in the end, ultimately speaks as to which market they want to go to under which scenario because there are different risks associated with the different markets, different scenarios – clearly less risk with utilization of existing pipe.

And I think the other thing is that - it won't drive the pipeline economics but you need to understand the NGL processing considerations. Alberta does face a methane shortage and does want to access the liquids. I'm not aware of any proposals that would not provide access to the liquids. Certainly the producers can [indisc.] contemplated liquids being stripped in Alberta but you can also do it commercially in Chicago. Those seem to be the two preferred alternatives at

> this time.
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> So really what we wanted to do was provide a perspective of some of the questions you might think about, some of the ways you might look at that information. But also Jack Crawford joined us because, as I mentioned, Alliance has just been through this process in terms of concept of a pipeline, looking at tolls, tariffs, looking at the regulatory perspective and the financing, and some of the things we talked about yesterday. So certainly we would be willing to answer any questions you have today.

SENATOR BUNDE said he understands the need for competition once Alaska gas reaches Alberta but expressed concern about the "dotted line" between the Alaska border and Alberta. He asked Mr. Carruthers his view of the challenges of building a new line in Canada between the Alaska border and Alberta instead of connecting with an existing pipeline.

MR. CARRUTHERS said the fact that the pipeline will cross a border is no different than other projects Enbridge has recently been involved with. He noted the engineering would be the same and Enbridge would not split the project at the border because there would be no sales there.

SENATOR BUNDE clarified that putting in an Alaska pipeline will require major congressional legislation to solve some Native American issues and he expects Canada to have to deal with some of the same issues with its First Nations peoples. He asked what challenges exist on a national level for Canadians to support a pipeline in that area.

MR. CARRUTHERS said Canada supports the development of natural gas. There was opposition to the production tax credit that was included in the legislation. The provinces support the development as well and the First Nations are supportive of pipeline development but want to assure that they benefit from the pipeline activity and that the environment is respected. He stated:

> But I think your question about the potential for aboriginal delay is very relevant and a good indication would be how the MacKenzie gas pipeline is being developed today and there [are] issues in terms of aboriginal support so it's a very important issue that needs to be considered. Relationships with the aboriginals will be key in Canada to development of the pipeline. But again, I think there's actually support for it, but it will have to be managed well and there is an expectation and a need for the aboriginals to have benefited out of the project.

CO-CHAIR OGAN asked if the Enbridge proposal is to phase in the amount of gas that comes down the highway and whether Enbridge wants to start with a 36 inch pipeline and add another one later.

MR. CARRUTHERS said he thinks consideration needs to be given in comparison to a 48 to 52 inch pipeline, which has the economies of scale and is a very competitive alternative. Another alternative that should be explored is the initial development of a 36-inch pipeline that would bring in the order of 2.5 bcf of gas per day and then subsequently looping another 36-inch line. The second line could be bigger depending on exploration activity and the market but that is a more measured approach that has less risk.

CO-CHAIR OGAN asked if the lines would primarily be buried.

MR. CARRUTHERS said yes.

CO-CHAIR OGAN thought digging two trenches for two pipelines would not be as cost effective as building one trench and putting a bigger line in to start with. He said he would be interested in getting more information on the costs because those costs will increase the tariff.

MR. CARRUTHERS said that is the key consideration. He said as the process goes forward, the commitment for shippers for gas will have to be determined. Clearly, building a larger line would not be useful if the commitments aren't there. The next consideration would be competitiveness of supply. Generally, there is more competitiveness on a more conventional build, which should reduce costs. The third consideration is that fewer funds would be used during construction before any revenue from the pipeline comes in. Enbridge sees less risk in a conventional build so it could be that the expected costs might be less on a 52-inch line. He said the crux of the matter is what commitments have been made to support it and how much risk is involved.

CO-CHAIR OGAN said the state wants to encourage development in the foothills where there are large quantities of gas. With a 36-inch line, that gas could be run for a long time but it would discourage development in other areas. He agreed that too much gas to market in the Lower 48 could affect pricing but he has heard the market will need as much gas as Alaska can produce unless nuclear or coal fired generation plants are built. He said the legislature wants to encourage the development of the frontier areas so it needs to consider how much that development will be delayed if the state starts off with a 36-inch pipeline.

MR. CARRUTHERS said in terms of exploration, there is a scenario in which a loop line would accommodate that better. It may be difficult for explorers to indicate a shipping commitment up front. But the expanded pipeline scenario might facilitate more exploration because companies could come in at the second round and the line could be sized even larger. He added that the phased approach would entail a longer construction period.

MR. JACK CRAWFORD, Executive Vice President, Northern Development, Enbridge, told members part of the flip side of that, in terms of looping, is that development could take place over a period of years. He noted the TransCanada pipeline was expanded in increments over a number of years and that levelized the construction boom in a significant way. He pointed out the Alaska line could be looped in increments if a lot of exploration took place, depending on how much gas was developed. Supply would be matched with transportation capability.

CO-CHAIR OGAN asked Mr. Crawford to explain looping.

MR. CRAWFORD said looping is another term for twinning the pipeline so a single line system today could be twinned by building a second parallel pipeline. Additional capacity could also be garnered by building short sections of loop along sections of the pipe. He noted that Alliance’s stations today are 120 miles apart. It could loop 30 miles and then the entire 120 miles over a staged period of time and get additional capacity at each juncture.

CO-CHAIR SAMUELS asked Mr. Crawford if he had a separate presentation.

MR. CRAWFORD said he did not but was available to answer questions.

SENATOR WAGONER asked Mr. Crawford his opinion of how FERC will exercise its authority over the distribution of the product going through the line once the pipeline is built.

MR. CRAWFORD said he shares some of the previous speaker’s concerns about some of the things FERC has done over the years that haven’t always made sense to him. However, he believes the concern that FERC would divert destinations or significantly impact the market is overblown. FERC has tried to step back and let the market work in the past few years. He believes FERC operates with the philosophy that it would prefer to let the market work rather than to be interventionist and dictate how the market should develop.

CO-CHAIR SAMUELS thanked Mr. Carruthers and Mr. Crawford and asked Mr. Palmer to present.

MR. TONY PALMER, Vice President, Alaska Business Development, TransCanada Pipelines, Ltd., told members there has been some commonality in what a couple of speakers have said with regard to facilities from Alberta to market and integration of facilities rather than constructing a bullet line beyond Alberta. He then began his testimony:

> The Alaska project will be a huge undertaking with large risks for all stakeholders. We believe the project should be limited to the frontier pipeline from Prudhoe Bay to Alberta and, at that point,

take an integrated approach from Alberta to market and that will give optimal results for Alaskan and Canadian stakeholders. By integrated, I mean that from the Alberta trading hub, which is the largest trading hub in North America, Alaskan gas will integrate into the existing North American gas pipeline grid and Alaskan gas at that point can flow east or west to markets across North America from San Francisco all the way to New York.

This is a map similar to what I had up yesterday, just to show the integrated approach – a little different color scheme. Actually I see that the color scheme doesn't actually show up that well on the screen but hopefully it does in your hard copy. You can see the Prudhoe Bay to Alberta system being a new piece of pipe at that point, going to an integrated approach.

You heard this morning from participants from Enbridge and Alliance with regards to their facilities. TransCanada's facilities within Alberta – we have about 15,000 miles of big inch pipe that you would be integrating into and we have another 9,000 miles of big inch pipe going across Canada or into the United States. We own the pipeline going east from Alberta into eastern Canada and ultimately service markets in eastern Canada and into New York and Boston. We own the piece of the pipeline that goes down, called Northern border, that goes down into Chicago and we own Foothills Pipelines, of course, the Canadian piece that connects to the borders, and we are soon to own what used to be called PGT, which is the line from British Columbia. On the map it's a greenish line running down to Northern California. It used to be owned by PG&E. It is still currently owned by them. We're in the process of closing that transaction.

So our 'B to C' Proposition has an integration with the TransCanada System at Boundary Lake, which is the dark blue line, as I mentioned, by extending the Foothills prebuild to that point.

Our underlying principle of our 'B to C' proposition recognizes that integration with the existing TransCanada system will best serve the interests of all constituents by fully utilizing the extensive natural gas pipeline grid and the spare capacity that exists on that grid today and is expected to continue when Alaskan gas flows.

Our proposal provides the most competitive and flexible economic solution for Alaska producers, Alaska royalty owners, and all affected constituents across a broad range of alternatives, we would argue.

What are key criteria and perspectives to examine when you're constructing a pipeline? Well, normally greenfield pipeline decisions are based on an analysis of routing, volumes, and capital cost. The shortest route with the highest volume and lowest cost would always be the preferred route.

However, there are a number of aspects to integration that we believe provide advantages over the normal distance, volume and capital relationships. Those major factors are volumetric requirements. The Alaska volumes are expected to ramp up over a 5-10 year time frame to 6 bcf/d. Our understanding at this point is that the major North Slope producers would anticipate commencing with a volume in the 4 to 4.5 bcf/day and expand from that volume. I spoke to that yesterday.

The last increment of that volume may depend on exploration and production activity once the pipeline is constructed. If you take 6 bcf/day and multiply that by a 25-year or 30-year life, there are insufficient proven reserves today so you would expect that drilling and other proving up would be undertaken over the course of the life of the project.

The liquids composition of the gas likely will change over this time frame as well. That's normal for a gas project. Because the range of potential outcomes is so broad, and may involve more producers than the initial three Alaska producers, the facilities planning for what's described as B to C, which is from Alberta to market, needs to be flexible.

The facilities planning for total supply, not incremental supply, is a very important factor from Alberta. I addressed some of that yesterday.

The interconnection with the existing grid can occur when the Alaska gas reaches Alberta. The Western Canadian Sedimentary Basin (WCSB) is producing approximately 17 bcf/d and the Mackenzie Delta can be expected to ramp up to 1.5 bcf/d. The additional Alaska gas of 4.0 or 4.5 bcf/d would create a requirement of about 22.5 bcf/d in total. This fundamental assumption drives the integration prospect that you're planning for a 22.5 bcf/d gas supply, not just planning for 4 to 4.5 bcf/d.

We believe that market flexibility will be very important for Alaskan gas. It's important for every other source of gas. They will look to attract and attach to the most attractive market and that market may change over time. Rather than constructing a bullet line to one particular market, we believe there's value for Alaskans as there is for Canadian gas in being connected to multiple markets. The combination of reduced Western Canadian supply and expansions on the existing pipelines driven by market factors prior to Alaskan volumes ramping up will influence the appetite to sign up for new greenfield pipelines from the basin.

Depending upon the marketing strategy and the existing commitments from each producer's portfolio, a variety of commitments may or may not be made. The Alaskan producers do not have to precisely match their additional Alaskan production with downstream market commitments as they may choose to sell some of their Alaskan gas within Alberta. That would be their choice. Clearly, you see today major producers seeking a portfolio of markets and a portfolio of terms and that's generally how they optimize their structure.

So what are the system integration benefits beyond what I've spoken to today? The Alberta system has several unique features that are not immediately evident when examining a map of the pipeline system that give Alberta several advantages.

The Alberta system is not operating at full capacity. You heard testimony from a number of parties yesterday to that effect and I heard that again this morning from the parties from Enbridge and Alliance. However, the Alberta system was partially offloaded by the construction of the Alliance pipeline so you had a facility that was built to match TransCanada's northern border system. Once Alliance was built and there wasn't a subsequent addition to gas supply out of Western Canada, you've effectively offloaded, unfortunately, our system because we had the shorter-term contract and you saw evidence of that this morning. New supply has not been robust enough to refill this capacity. This spare capacity can handle some volumes with no incremental construction costs, no incremental environmental impact. Additional compression can further add volumes with little incremental cost.

The net supply additions and demand requirements on the Alberta system are also shifting. If you look at the map of Alberta, you should be aware that the supply in the northeastern section of Alberta near the oil sands, near Fort McMurray, is declining. That is in addition to having an increase in demand in that region so you have two factors that are unloading the pipeline system on the northeastern section of Alberta and there's likely to be a pipeline constructed by us in addition to our existing facility to connect the northwest part of our province with the northeastern part of the province to meet that incremental demand from gas entering in from either western Alberta or northeastern B.C. That is likely to happen in the next several years. That will also improve the integration benefits for this project. This shift in the system load creates a low-cost addition of incremental capability from the northwest to the southeast portion of the Alberta system.

I'd like to address construction costs. The single largest variable having the biggest impact on the toll, on the pipeline tariff, is the construction cost. You've heard that from a number of parties. The estimation of the costs is influenced by pipe size and by competition for resources if both 'A to B' and 'B to C' are constructed in a two-year time frame with the same pipe size, the same compressors, the same valves. Construction of a smaller sized 'B to C' pipeline, as necessary, with more conventional pipe sizing, not only increases the certainty around the construction cost estimates but reduces the competition for steel mill space that would influence the costs of the A to B portion of the pipeline as well. Clearly there is going to be a worldwide supply of steel pipe for this project. That is going to be a necessity. It's very clear that North American mills can be competitive, however they will not supply 100 percent of the steel pipe for this project. If there's a variation in pipe size to Alberta and away from Alberta, that will bring more competitors to that marketplace, not only in the steel business, but in the valve business as well as the contractors. We think that's to the benefit of all parties.

The roll-in, and I believe that term has been described here before - roll-in simply means an averaging of old costs and new costs, but the roll-in of new capital expenditures with existing capital investment to create a toll charged to shippers also influences the capital obligations. In a rolled-in toll, the incremental capital is proportionally less so the impact of a hot construction market is less in the blended average toll. Clearly, one of the fears that you heard me describe yesterday with regards to a potential cost overrun, is there's real potential on a project of this scale for a hot construction market and that environment can affect capital cost overruns. It's prudent to try to minimize that.

Toll integration – so integrating the toll would also have a mitigating effect on construction costs because the system costs are essentially spent today and will be unlikely to increase over the planning horizon. The tariff design in Alberta has created an expressway toll concept from the northwest portion of the province where the 'B' is, near the British Columbia border, and therefore all the way through to the southern portions of the province of Alberta and into the export market. Therefore future additions are likely to have a smaller toll impact at Boundary Lake.

Another advantage of the Alberta system that is often not appreciated is the volumetric size of our system. System receipts are approximately 11.5 bcf/d today, and the export deliveries are approximately 10.0 bcf/d. So those are volumes in the two and three times the expected Alaska volumes. That's the system you would be integrating into. The size of our system adds tremendous stability to the toll. It changes very slowly, very insignificantly, if you add volumes of gas and variances in volumes are relatively small so the toll does not change significantly.

Just to summarize - our integration model is flexible and it appeals to a broad cross section of market participants. Consequently the regulatory approval for this solution is likely to be less contested and, in fact, supported by more interested parties, a very important factor we would argue.

And a key to the integrated approach is to continually monitor the requirement for facilities and to be poised to gain market support for the timely addition of new facilities.

I would like to address a few scorecard items as to how we compare – our integrated proposition with other alternatives. We believe that an integrated solution is more attractive and will be more attractive to Alaskans and Canadians. It's economically superior to any alternative for an independent pipeline – separate pipeline - from Boundary Lake through a broad range of Western Canadian supply and capacity scenarios. You've heard my testimony as well as others that Western Canadian supply and demand numbers are changing. Our forecasts are changing, have changed over the past two years, and I believe that's common across the industry. We are less optimistic about Western Canadian supply than we would have been two years ago. We also believe that demand will not grow as quickly as we expected. But fundamentally, the gap - the spare capacity in the pipeline is growing and depending on what happens over the next several years, you may or may not be constructing additional facilities away from Alberta to serve Alaska gas. That will depend on what happens with parties' actual forecasts.

One of the key advantages for integration is you can defer the decision on constructing the specifics of pipelines beyond Alberta. The time frame to strike a commercial deal on the project in advance of in-service from A to B – from Prudhoe Bay to Alberta as I described yesterday in my testimony, in our case is seven years so if there's a commercial deal struck next year, we have indicated we can be in service to Alberta by 2012. If you want to be in service by 2012 from Alberta away to whatever market you're seeking from San Francisco east to New York, if you're using existing facilities, clearly that commercial deal can be struck several years later than 2005. If you want to build a new pipeline or some component of the additional volumes needs a new pipeline, you also have a significant time frame lag of approximately two years. You wouldn't have to make the decision on the downstream pipeline increment until about 2007. That's a two-year advantage to see what's happening in the marketplace with supply and demand in Western Canada and also to see what's happening in overall markets. We would argue having additional time is very valuable. It generally means you make a better decision.

So, just to walk through some scorecard items – we think that an integrated approach will provide the highest netback price to producers and royalty gas netback owners at Boundary Lake. The tolls – there will be more stable tolls across a wide range of western Canadian supply and demand forecasts - lowest tolls and fuel compared to alternatives. The TransCanada Alberta system tolls receive an immediate benefit from Alaskan gas. That will be attractive to Canadian producers and that will be attractive to the Canadian government I would argue as well.

Capital and warranty costs – the lowest infrastructure capital cost across different pipe size alternatives away from Alberta.

Lowest warranty capital cost. By warranty capital I mean the commitment cost to commit for pipeline demand charges away from Alberta will be lower because fundamentally the existing pipelines do not require 15 and 20 and 25 and 30 year contracts. As you heard testimony this morning, on existing pipes you can contract for one-year worth of service with renewal rights and continue to roll forward that contract if you wish. You can also get expansions on our system in Alberta with a 5-year contract rather than a 15 to 30 year contract. That has value for parties that are making commitments.

Flexibility – We believe that having access to liquids processing within Alberta will have value. Clearly there may be liquids removed within the state of Alaska. There may be liquids removed within Alberta and there may be liquids removed on the way to market. Having additional access to liquids removal facilities will give Alaskan gas one more opportunity to sell their liquids. You'd be connected to an extremely liquid Alberta hub at AECO, and you also hear another term sometimes called NIT – that's Nova Inventory Transfer that's on our existing system. That is the most liquid hub today in North America – more liquid than NYMEX.

Easy access to flexible and diverse markets away from Alberta Hub – I think I've addressed that, and the shortest lead-time for capital decisions. I've also addressed that for new capacity away from Alberta.

Risk mitigation – also important - lowest risk of 'hot-market' cost overruns. Spread the downstream risk at the integrated hub by having more participants in new capacity may not require additional downstream facilities, depending on the timing and volume of Alaskan flows, and the existing certificates provide the lowest regulatory risk and fastest in-service.

I would wrap up by indicating that the integrated TransCanada Foothills proposition – Foothills Pipelines is now 100 percent owned by TransCanada. They have held the certificates for constructing the Alaska pipeline project within Canada, including B to C, since 1978. They have met those commitments and still hold those certificates today and, as you would have seen from the map, they have an existing pipeline today called the prebuild that has capacity of about 3.3 bcf/d from central Alberta to the Lower 48 interconnects.

The underlying principle of TransCanada's proposition is integration of Alaskan gas into its existing grid, including the Foothills prebuild. The concepts that originally underpinned the Foothills certificates are still valid today and we would argue the overall public interest will best be served by fully utilizing the extensive natural gas pipeline that currently supports Canadian and American gas consumers.

To conclude, the benefits of integration are many and substantial. The economic advantages in capital and warranty costs will not only provide lower prices to consumers, but also higher netbacks to resource owners. What was true in '78 remains true today, that TransCanada and Foothills can provide the most beneficial products for the development of Alaska reserves.

Thank you for this opportunity to appear at this session today and I'm available to respond to your questions.

SENATOR HOFFMAN asked Mr. Palmer to address any consideration given by TransCanada of the potential benefits of this proposal to Alaskan consumers, in particular to consumers along the river system and coastal communities, and of the spur line.

MR. PALMER said the original project, which TransCanada is a proponent of, always anticipated volumes would be taken off of the line at several locations to connect to Alaskan communities. TransCanada's focus is the main line from Prudhoe Bay through Alaska to market but off takes from the line to serve Alaskan consumers were always contemplated. Valves and connections would be built and Alaskan and other investors would pursue constructing those laterals. He noted the original legislation contains specific language regarding reasonable tolls to Alaskans and making gas available to Alaskans.

SENATOR HOFFMAN thanked Mr. Palmer for addressing benefits to Alaskans as that topic was missing from his presentation.

SENATOR WAGONER asked if the 3.3 bcf/d capacity in the system is additional capacity that is not currently being used.

MR. PALMER said that is currently fully utilized and contracted by Alberta Gas. The project was initially constructed because there was seven years of spare Alberta gas at the time in the 1980s, which subsequently turned out to be more than that. It is fully contracted today, generally on a short-term basis. He believed the remaining terms on those contracts would be one through four years. At the time Alaska gas comes on line, Alaska gas would have that as an alternative, as would Alberta or Western Canadian gas.